–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	))))))))))	**DOCKET NO. UT 20-035-04** **Exhibit No. DPU 11.0 DIR**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

BRUCE R. CHAPMAN

September 15, 2020

INTRODUCTION

Q. Would you please state your name and business address?

A. My name is Bruce R. Chapman. My business address is 800 University Bay Drive, Suite 400, Madison, WI 53705.

Q. By whom are you employed and in what capacity?

A. I am employed by Christensen Associates Energy Consulting, LLC (CA Energy Consulting) in the capacity of Vice President.

Q. Would you please describe Christensen Associates Energy Consulting, LLC?

A. Christensen Associates Energy Consulting is a wholly owned subsidiary of Laurits R. Christensen Associates. Our consulting group is a full-service consulting firm focused on applied economics, with four practice areas consisting of transportation, energy, litigation support, and analytical support in the form of productivity studies for the U.S. Postal Service. We have served the electricity and natural gas industry since 1976, and our senior staff has decades of experience, including testimony and official reports on a variety of topics, as filed before numerous state and federal regulatory authorities in the U.S. and Canada, including the Federal Energy Regulatory Commission.

Q. Would you please describe your background and professional responsibilities?

A. I have been employed for over thirty years by Christensen Associates Energy Consulting or its parent. I consult with regulated utilities, regulators and industry stakeholders on matters of costing, retail pricing and rate design. As a vice president, I interact regularly with current and prospective clients, prepare proposals and represent our firm in competitive evaluations of proposed work. I supervise and participate in research projects for our clients, typically with a team of CA Energy Consulting professionals. I also present project results to clients and regularly make public presentations at industry conferences and workshops.

Q. Would you please state your educational background and experience?

A. I hold an M.A. degree from the University of Wisconsin-Madison, in economics; and completed the course work for a Ph.D. My professional experience consists predominantly of economic consulting with CA Energy Consulting in positions of increasing responsibility. My recent work includes cost-of-service (COS) analysis for regulated utilities and rate design based on established regulatory and market-based principles. I have assessed comprehensively utilities' retail rate portfolios and assisted them to design innovative market-based rates across the full range of the retail spectrum from real-time pricing through time-of-use to fixed billing. From 2010 to 2018 my colleague, Robert Camfield, and I served as economists for the Nebraska Public Service Commission's Natural Gas Division, for whom we performed evaluations of rate applications and cost-of-service (COS) methodology for the information of the Staff and, hence, the Commissioners. My resume is attached as Appendix A to this testimony.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Division of Public Utilities of the Utah Department of Commerce (the Division).

Q. Have you previously provided testimony before the Utah Public Service Commission?

A. No.

Q. What is the purpose of your testimony?

A. My testimony provides comments upon and addresses issues arising from my review of Rocky Mountain Power's (RMP's or the Company's) COS study, as set out in the testimony and workpapers of witness Robert M. Meredith.

Q. How is your testimony organized?

A. I first provide a summary of our findings and recommendations. The main body of our testimony is presented under three headings: 1) Issues Associated with Production and Transmission; 2) Issues Associated with Distribution; and 3) Other Issues.

SUMMARY OF TESTIMONY: FINDINGS AND RECOMMENDATIONS

Q. In your opinion, is the RMP COS Study conducted in compliance with industry standards of costing methodology?

A. For the most part, yes. The COS study undertakes the allocation of jurisdiction costs to Utah customers using costing methods which are largely in keeping with contemporary industry practice, as set out in the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual (NARUC manual), the leading recognized source of COS methodology in North America. RMP undertakes the main steps of functionalizing, classifying, and allocating costs using methods that are well known and generally accepted. [1]

Q. In your opinion do the testimony and workpapers of witness Meredith adequately document RMP's methods?

A. Yes. The testimony documents and defends the utility's methodology and explains its few proposed changes. The testimony also sets forth the utility's general statement of methodology.

Q. Would you please summarize any exceptions to the above statements that are discussed in your review below?

A. There are instances in which RMP's COS methodology appears to depart from industry practice.

- RMP's approach to the classification of production (excluding fuel) and transmission costs (75% demand-related and 25% energy-related) adheres to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (Protocol).[2] The Protocol determines the classification rule through 2023 but the classification methodology would likely be

[1] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992. See pages 33-68 for production and pp. 69-85 for transmission.
[2] Meredith, at lines 135-140.

improved if RMP were to select one of the many methods discussed in the NARUC manual.

- RMP does not use the common forms of distribution cost classification, but instead classifies each FERC distribution account as either entirely demand-related or customer-related.[3] Common practice involves statistical analysis to split some of the large accounts (FERC accounts 364-368) between the two cost causation factors.
- Another issue is associated with the allocation of the federal income tax adjustment that results in a proposed rebate for the next two years. The allocator used for this rebate (rate base) appears not to replicate the allocation approach used for income tax itself.[4] Income tax liability results from multiple deductions from revenue, with each deduction having its own allocation procedure. The income tax adjustment might have been allocated on a representation of revenues instead of rate base. However, this change appears to result from a previous stipulation and order specific to the tax adjustment. As a one-time change there appears no need for further review.

Q. What recommendations do you submit for consideration to the PSC?

A. I submit the following recommendations:

- <u>Regarding production and transmission cost classification</u>, I recommend that the PSC ask RMP to consider alternative approaches in time for the review of the 2020 Protocol in 2023.

[3] Meredith, at lines 141-148.
[4] Meredith, at line 295.

- Regarding distribution cost classification, I recommend that RMP investigate the common alternatives to its current methods. I recognize that there is a tradeoff between improved classification accuracy and computational complexity.

ISSUES ASSOCIATED WITH PRODUCTION AND TRANSMISSION

Q. Does your review of the RMP COS study raise any issues regarding the production and transmission functions?

A. Yes. One issue arises in the approach to the classification of production and transmission costs. RMP classifies non-fuel production and transmission costs as 75% demand-related and 25% energy-related, a practice set out in the company's 2020 Protocol, itself the result of a Multi-State Process (MSP).[5] The Protocol enables equitable sharing of RMP's revenue requirements across the jurisdictions in which it operates.

Q. What does the 2020 Protocol state regarding the classification rule?

A. Section 3.1.1, Classification of Interim Period Resources, states, "All Fixed Costs of Interim Period Resources will be classified as 75 percent Demand-Related and 25 percent Energy-Related."[6] This is a continuation of methodology established in the 2017 Protocol, the 2020 Protocol's predecessor.

[5] Exhibit JRS-1 of Direct Testimony of Joelle R. Steward, Docket No. 19-035-42.
[6] 2020 Protocol, lines 148-151.

Q. Does the 2020 Protocol impose a cost allocation requirement on the State of Utah re RMP's COS study?

A. Formally, no. As the 2020 Protocol states, "Nothing in the 2020 Protocol is intended to abrogate any Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon applicable laws and the record established in rate proceedings conducted by that Commission; (2) consider the effect of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) **establish different allocation policies and procedures for purposes of allocating costs and revenues within that State to different customers or customer classes**.[7] (Emphasis added.) However, from a practical perspective, methodological uniformity across jurisdictions simplifies RMP's task of cost allocation by facilitating the use of a single rule for all jurisdictions.

Q. Should the Utah PSC be concerned about the apparent difference between the Protocol's stated intention and its application in this case?

A. Probably not in this case, despite the significance in terms of the proportion of cost to serve that is affected. First, this sharing rule is long-established rather than newly introduced. Second, the changes in RMP's generation mix (exiting from coal and the increasing use of renewables) that are described in the application suggest that by 2023 there may be reason to review the rule as part of the next protocol, rather than as part of this rate application.

[7] 2020 Protocol, lines 48-54.

Q. What should RMP consult, should it review its cost classification methodology?

A. There is a wide variety of methodologies available and in current use. The NARUC manual sets out classification (and allocation) alternatives in some detail.

Q. What are the leading approaches set out in the NARUC manual?

A. The approaches used for classifying production costs can differ from those of transmission. Production classification methods has been of two main types: demand-only or energy weighting (combined demand and energy) methods. The former is based on the hypothesis that physical facilities are put in place in order to satisfy peak demand. The latter is based on a perception that production facilities are constructed for a mix of demand-related and energy-related reasons. Specifically, energy weighting methods recognize that a utility chooses to invest in a mix of base, intermediate, and peak production capacity. A baseload plant will be viewed as predominantly energy-related, while a peaking plant may be predominantly classified on the basis of peak demand. Both demand and energy weighting methods are recognized in the industry. Within each method, utilities can avail themselves of a variety of cost allocation methods, selecting a method that appears to best represent cost causation for their utility.

Regarding transmission classification, a somewhat narrower range of alternatives than those available for production classification applies. Some jurisdictions view transmission as an extension of production and simply apply the same classification (and allocation) methodology to transmission. However, unlike production, transmission does not have analogous differences in type of transmission investment in serving base, intermediate and peak system loads. As a result, demand methods are more readily justified than for production cost classification.

Q. To what extent is the RMP approach at variance with the methodologies set out by NARUC?

A. The outcome of the RMP approach, division of classification between demand and energy, is not at variance with industry practice. However, apparent absence of a methodology that obtains the 75:25 split is unusual. This may simply be an artifact of a long-established practice in the jurisdiction, or across RMP's several service territories and regulatory jurisdictions, and precedent certainly counts in determining how best to proceed. However, the significance of production and transmission costs in total utility costs suggests that the utility's classification methods should eventually be supported by a defensible methodology.

Q. Does the NARUC manual recommend a specific method or methods?

A. No, it does not. The NARUC manual confines itself to listing and describing alternatives.

Q. Do you suggest preferred methods based on your experience?

A. Yes, there are a couple of production classification methods that I would suggest deserve review. If embedded cost-based methods are preferred, the equivalent peaker methodology has merit from a theoretical perspective. As the NARUC manual states, "Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added." That is, the equivalent peaker method codifies generation expansion plans and their underlying objectives as mathematical algorithms for cost classification.

Q. What other method do you believe merits consideration?

A. Utilities and regulatory jurisdictions, in using embedded cost-based classification methods, can become embroiled in debates as to the relative shares of demand and energy cost causation. An alternative is to make use of load-weighted marginal cost as an allocator, thereby finessing the classification issue. In this approach, marginal costs, including both energy and capacity/reliability costs, in hourly representation are multiplied by class hourly load profiles to yield total marginal costs by class. The allocator is simply each class's share of total marginal costs, and there is no need to determine the shares of cost that are demand- and energy-related. More generally, the attraction of marginal cost-based cost allocation is the alignment of cost allocation with the inherent resource efficiency properties of marginal cost pricing.

Q. Would a marginal cost-based allocator be volatile relative to embedded cost-based allocators?

A. Perhaps, but I offer two considerations. First, embedded cost-based allocators can change over time as algorithm inputs change. Second, if a marginal cost-based allocator changes due to changes in marginal costs, then it is appropriate that the resulting allocator weights change. For example, if marginal capacity costs rise relative to marginal energy costs, then it seems sensible that rate classes that have load profiles that coincide with periods of high marginal cost under the new configuration should be responsible for an increased share of costs. Arguably the change in shares matches the change in cost to serve.

Q. These alternatives seem to be focused on production. Does this mean that you recommend that the use of a common methodology for production and transmission cost classification should give way to separate cost classification methods, one for production and one for transmission?

A. Not necessarily. However, departure from a common methodology based on a rule of thumb to determine demand and energy shares would increase flexibility in cost classification. Such a change may well be necessitated if an equivalent peaker methodology or other methodology is adopted by RMP and approved by its regulatory authorities. Such a change would not necessarily be required for marginal cost-based cost allocation, providing that the pattern of hourly marginal costs includes energy and reliability cost elements for production, as well as load-related marginal capacity costs, and marginal line losses in the case of transmission.

Q. Does RMP's proposed subfunctionalization of costs affect the consideration of alternative methods of cost classification?

A. No. Separation of costs into fixed and variable components helps to clarify how costs are likely best classified. However, the issue of how to classify many fixed costs remains unresolved.

Q. Would you please summarize your view on RMP's production and transmission cost classification method?

A. The RMP method is long-established and facilitates cost allocation uniformity and simplicity across jurisdictions, and an immediate change would disrupt the 2020 Protocol. For the future, RMP should explore alternative classification methods, including those identified here (equivalent peaker and marginal cost-based methods) to produce a classification of production and transmission costs with a formal computational approach in line with industry methods.

Q. In allocating demand-related production and transmission costs, RMP uses a 12 CP allocator. Is this an issue of concern?

A. No. While alternatives are available, the 12 CP allocator is well recognized. Additionally, the pattern of PacifiCorp peak demands found in the workpapers suggests that RMP is part of a system that is not strongly seasonal. (See file COS UT GRC 2020.xlsx, sheet *Inputs*.)

ISSUES ASSOCIATED WITH DISTRIBUTION

Q. Do you perceive any issues with respect to RMP's handling of distribution costs?

A. Yes. RMP classifies its distribution costs, account by account, as either demand-related or customer-related. While meters and service lines are deemed customer-related, other costs are deemed demand-related. This approach is different from common industry practice for costs other than those related to services and meters (customer-related) and substations (demand-related). The standard approach is based on a hypothesis that much of the distribution system (poles, underground conduit, conductors, and transformers) has both demand-related and customer-related properties and that these properties ought to be reflected in the classification methodology.

Q. Does the NARUC manual describe these methodologies?

A. Yes. The NARUC manual identifies two approaches.[8] One approach, the "Minimum Size Method," classifies a hypothetical distribution system that serves all accounts but only at minimum load as customer-related, with the residual relative to the actual distribution system as being demand-related. The second approach, the "Minimum-Intercept Method," statistically analyzes each component of the existing system by regressing equipment size or capacity on cost to arrive at a zero-capacity cost per unit for the component. Multiplying by the number of units yields the customer-related share of cost. The residual is deemed demand-related. There are strengths and weaknesses to each approach, and both are accepted by the industry.

Q. What do you infer from this practice?

A. I infer that RMP would strengthen its methodology either by producing a methodological defense of its approach to classifying distribution costs or by investigating whether one of the approaches identified in the NARUC manual would improve its classification procedures for distribution costs.

[8] See Chapter 6, pages 90-95.

OTHER COS ISSUES

Q. This rate application includes the federal tax act adjustment. In your opinion, is the adjustment reasonably allocated?

A. Yes, but RMP's approach raises an issue. While the timing of the rebate is not a COS matter, its method of allocation is worth reviewing. RMP used its F101 allocator, Rate Base, for this task. (Resulting prices are percentage discounts of Power and Energy Charges.)[9] Utilities have some discretion in how income taxes are allocated, and this discretion surely applies to a corporate income tax rebate. However, RMP calculates each class's income tax liability by deducting from class revenues a number of line items and then applying the federal tax rate to the remainder.[10] A symmetric approach to the income tax rebate might be to allocate the rebate based on share of class taxable revenues before the deduction, rather than rate base. Any debate on this issue appears to be precluded, though, by the outcome of a previous proceeding before the PSC. A stipulation and order in Docket No. 17-035-69 determine how the tax adjustment is to be handled.

Q. RMP's assets include a coal mine upstream from its production assets. The COS study functionalizes the mine as miscellaneous assets (assigned subsequently to production), classifies it as energy-related, and allocates its costs to rate class based on the F30 allocator (MWH at generation level). Is any aspect of this methodology problematic?

[9] Meredith, lines 293-296.
[10] See Meredith, Exhibit RMM-3, p. 9 of 10, for a list of these items.

A. The asset itself is unusual in an electric utility portfolio. However, RMP’s cost treatment of the asset appears reasonable.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

Bruce R. Chapman

RESUME

January 2020

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Academic Background:

All course work necessary for PhD, University of Wisconsin–Madison, 1981, Economics
MA, University of Wisconsin–Madison, 1979, Economics
BA, University of Pittsburgh, 1976, Economics

Positions Held:

Vice President, Christensen Associates Energy Consulting, LLC, 2015-present
Senior Economist, Christensen Associates Energy Consulting, LLC, 2005–2014
Senior Economist, Laurits R. Christensen Associates, Inc., 1992–2005
Economic Analysis Consultant, Laurits R. Christensen Associates, Inc., 1988–1992
Research Economist, Laurits R. Christensen Associates, Inc., 1986–1988
Associate Consultant, Coopers & Lybrand Consulting Group, Economics Practice, Toronto, Canada, 1985–1986
Research Assistant, University of Wisconsin-Madison, 1980–1981
Research Analyst, Woods Gordon (Economics Group), Toronto, Canada, 1979–1980

Professional Experience:

I assist clients in the electricity and natural gas industries to improve their costing and pricing capabilities. I advise clients in such areas of expertise as: cost-of-service analysis and rate design based upon established regulatory and market-based principles; innovative rate design including demand response products, renewables pricing, fixed billing, and other market-based retail pricing products; load forecasting and load research analysis. I supervise and conduct analysis of costing and pricing issues for utilities, regulators, customers and other industry stakeholders. Additionally, I have supervised the development of software required for the implementation and support of innovative retail products. Examples include cost-of service and rate design models to support rate applications, and models to predict customer tariff choice and price response. I regularly present costing and pricing issues and concepts at industry conferences and workshops.

Major Projects:

Prepared a memorandum reviewing a government-owned utility's market overview of an RTO's wholesale pricing components and comparability with other jurisdictions.

Assisted a utility to prepare testimony on a proposed electric fixed-bill experiment.

Assisted a Canadian utility to develop time-varying pricing for large customers.

Supported the preparation of a rate application by a natural gas utility.

Evaluated the advisability of contracted rate administration services for a vertically integrated utility.

Prepared an analysis of demand-side management cost allocation practices for a Canadian utility.

Reviewed alternative corporate treatment non-utility services by a Canadian utility.

Prepared an analysis of non-utility service marginal costs for a Canadian utility.

Supported a Canadian utility's rate filing with testimony on cost-of-service issues.

Conducted a review of commercial rate designs and rate levels across a sample of American electric utilities.

Prepared a survey of wholesale electric contract structures for a southeastern utility.

Conducted a comprehensive review of the retail rates of a hydro-electric generation dominated Canadian utility.

Conducted a comprehensive review of the retail rates of a Canadian utility with a conventional generation mix.

Prepared a cost-of-service study for a Great Plains electric utility.

Reviewed economic development and load retention rates for a Canadian utility.

Evaluated behavior of fixed billing customers following instances of very high consumption.

Reviewed the retail rate portfolio of a Canadian utility with respect to industry standards.

Reviewed the cost causation underpinnings of a utility's residential rate design.

Collaborated in a review of standby rate structures for a Midwestern utility.

Provided pricing and revenue recovery guidance to a Caribbean utility.

Provided guidance to a Southeast Asian utility in the design of time-of-use rates. Guidance included instruction in simulation of price response.

Directed a cost-of-service study for a large distribution utility.

Assisted a utility to adjust its costing and pricing methods following addition of significant new generation and transmission assets.

Assisted a utility to merge rates of two separate service territories following a corporate merger.

Reviewed a natural gas distribution utility's proposal for a commodity hedging arrangement.

Assisted in developing an electric vehicle tariff for a Midwestern utility.

Assisted in an evaluation of economic development and load retention rates for a Midwestern utility.

Led an evaluation of a Midwest utility's residential time-of-use rate in comparison with other TOU designs and current marginal costs. Evaluated means by which participation could be increased.

Participated in an evaluation of the merits of a special contract for a large customer of an Eastern utility.

Conducted an analysis of the relative cost-of-service implications of creating a separate class for a specialized subset of customers from an existing large customer class.

Assisted a Great Plains utility to develop a renewable tariff for large industrial customers.

Managed a project that assisted a Great Plains public service commission staff to evaluate natural gas utility submissions for safety-related cost recovery via new riders.

Participated in a load research data development project for a Midwestern utility, including sample design and selection, and class interval load profile development.

Conducted an analysis of the cost implications for a Caribbean utility of introducing LED street lighting.

Developed generic cost-of-service and rate design models for use in client rate cases.

Customized company cost-of-service and rate design models for an Asian utility. The project also included support for marginal cost capability development.

Led a rate case preparation process for a Southeastern utility that included load and energy forecasting, development of revenue requirements, and support for cost of service and rate design.

Participated in a Midwest utility's rate case by reviewing current mass market time-of-use and other rate designs and recommending modifications.

Collaborated in a review of a large Canadian utility's cost-of-service methodology, including a public review process with stakeholders. Testified before regulator regarding recommendations.

Conducted an assessment of a Great Plains public power utility's plans for three pricing concepts: green power, economic development rates, and unbundled retail pricing to facilitate customer choice.

Assisted a distribution utility to review aspects of its distribution cost allocation methodologies by conducting a survey of methodologies across a number of electric utilities.

Assisted a state energy office to review ways in which the state could improve its record of energy efficiency program achievements, as recorded by the ACEEE Scorecard.

Collaborated in the development of rate redesign alternatives for a utility's real-time pricing program structure.

Collaborated in the review of the potential for a Canadian utility to introduce a fuel adjustment mechanism.

Conducted an analysis of probable migration of customers to new time-of-use electricity programs offered by a southeastern utility.

Evaluated the accuracy of an electric utility's fixed bill offer algorithm and recommended modifications.

Led a project which conducted a review of an electric utility's avoided cost calculation and the application of those costs in energy efficiency reviews.

Managed and participated in reviews of rate and gas cost adjustment applications for a Great Plains public service commission's gas division.

Conducted a cost-of-service and rate design study for a Caribbean utility in preparation for a rate submission.

Supported review for an industrial customer group of a large filing by a utility, focusing on non-bypassable riders.

Managed a gas cost review process for a Great Plains regulatory agency.

Analysis of smart grid pricing issues for a Great Plains public power utility.

Contributed to load research sample development for an investor-owned utility.

Managed a review of a large electric and gas utility's costing methodologies.

Managed a cost-of-service and rate design study for a Caribbean utility.

Conducted analysis of distribution costing practices at a large Midwestern investor-owned utility.

Development of a time-of-use rider for two electric utilities.

Management of a study of interruptible pricing program improvements for a large Midwestern utility.

Management of a comprehensive cost-of-service and rate design study for a Caribbean utility.

Strategic pricing for a large hydro-dominated utility.

Evaluation of the net economic benefits of alternative power supply strategies: coal vs. renewables and energy efficiency.

Load forecasting project for a medium-sized electric utility with significant industrial load.

Analysis of alternative means of net metering.

Evaluation of alternative demand response programs for a municipal utility.
Analysis of treatment of margins from real-time pricing.
Analysis of a natural gas energy conservation funding mechanism.
Design and pricing of a small customer Time-of-Use program.
Evaluation of cost of capital for a small Caribbean utility.
Risk pricing of a long-term customer choice retail contract.
Evaluation of response by small customers to fixed billing programs.
Evaluation of response by medium-sized customers to a banded fixed billing program.
Cost-of-service project including marginal cost and traditional cost basis.
Preparation of load research survey sample via stratified random sampling.
Design and pricing of a Critical Peak Pricing product
Evaluation of residential customers' propensity to adopt a voluntary Time-of-Use product
Pricing of a fixed bill product for a new service territory based on response elsewhere
Evaluation of peak period response to a fixed billing product
Development of an electric utility fuel forecast
Customization of fixed bill software for use at a utility site
Design and pricing of a Banded Fixed Billing product.
Long-term wholesale power procurement for an electric utility.
Report on Adoption of Variable Pricing contracts in deregulated retail electricity markets.
Development of Fixed Bill software to generate offers and monitor customer behavior.
Quantitative evaluation of net benefits of demand response programs.
Quantitative evaluations of customer response to fixed billing.
Design and pricing of several pilot and permanent fixed-bill programs.
Development of Efficient Tariff Prices via Marginal Costing.
Analysis of Market Data Available to Estimate Marginal Cost of Reliability.
Evaluation of Risk of Fixed Billing Based on Customer Response.
Cost Allocation Analysis for Rate Case Filing.
Analysis of Customer Response to Fixed Billing.
Fixed Bill Scoping for a Natural Gas Provider.
Analysis of Risk Implications of Fixed Billing for an Electric Utility.
Strategic Assessment of an Electric Utility's Retail Tariff Portfolio.

Guaranteed Bill Product Design and Risk Assessment.

White Paper on Interruptible/Curtailable Service.

Marginal Cost-Based Cost of Service Development.

Software Scoping for Self-Designed Products.

Flat Bill Offer Software Development.

Comprehensive Rate Repricing.

RTP Price Hedging Product Development.

Retail Pricing Under Competition Conference.

Rate Optimization Plan.

Fixed Bill Product Development.

Weather Hedge Evaluation.

Real-Time Pricing Product Development.

Workshop: Creating a Diversified Retail Pricing Portfolio.

Product Mix Business Plan.

Prepared material for testimony in Federal District Court on Real-Time Pricing.

Risk-Based Pricing Workshops.

Survey of New Electricity Market Players.

Analysis of Fixed Bill Products.

Strategic Pricing Plan for a Midwestern Utility.

Product Mix Analysis for Small Customers.

Real-Time Pricing Workshop.

Innovative Pricing and Marginal Costing for a Co-op.

Real-Time Pricing with Multiple Options.

Real-Time Pricing for a G&T and its Co-ops.

Product Mix Analysis for Large Customers.

Real-Time Pricing Service Design for Commercial Customers.

Advanced Service Design Workshop.

Real-Time Pricing Program for a Midwestern Utility.

Evaluation of Customer Response to Real-Time Pricing.

Real-Time Pricing Program Development for an Eastern Utility.

Two-Part Pricing Service Design.

Real-Time Pricing Regional Workshops.

Real-Time Billing Program Support and Revision.

Electricity Efficiency Programs.

Real-Time Pricing Program Redesign for an Eastern Utility.

Real-Time Pricing Implementation for a Canadian Utility.

Real-Time Pricing Practitioners' Workshop.

Real-Time Pricing for a Canadian Utility.

Customer Evaluation of Real-Time Pricing.

Review of Competitive Pricing Strategies.

Evaluation of Process of Marketing Real-Time Pricing.

Review of Methods for Distinguishing Customer Response to Rate Change.

Real-Time Pricing Rate for a Southern Utility.

Review of Accounting and Incentives for a Real-Time Pricing Rate.

Analysis of Load Impact of Priority Service Alternatives.

Benefit/Cost Analysis of an Integrated Energy Management System.

Benefit/Cost Analysis of Marginal Cost-Based Rates for DSM Integrated Resource Plan.

Impact Evaluation of Curtailable Electric Service.

Survey of Households Who Were Candidates for Voluntary Time of Use Rates.

Audit of Energy Management Software.

Real-Time Pricing Rate for a Large Northeastern Public Utility.

Software Design for Real-Time Pricing.

Improved Approaches to Estimating Benefits of DSM Programs.

Load Shapes Assessment Program.

Fuel Purchase Contract Study.

Evaluation of the Effects of Canadian Energy Policy.

Evaluation of Energy Conservation Programs.

Professional Papers:

"Pricing Distributed Generation: Challenges and Alternatives," *Natural Gas & Electricity*, March 2017.

"Pricing of Renewable Energy Made Difficult by Policy Challenges," *Natural Gas & Electricity*, January 2016.

"Room for Fixed Billing in the World of Conservation?," *Natural Gas & Electricity*, August 2008.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, June 2001 (with Ahmad Faruqui, Dan Hansen, and Chris Holmes).

"A Survey of Real-Time Pricing Programs," *The Electricity Journal*, August–September 1993 (with Juliet Mak).

"Real-Time Pricing: DSM at Its Best?," *The Electricity Journal*, August 1990 (with Tom Tramutola).

Conference Presentations:

"Green Tariff Pricing Structures", EUCI's Utility Green Tariff Conference, Denver, Colorado, September 2019.

"Cost Factors Inducing Change in the Pricing of Distributed Energy Resources", EUCI's NEM and Utility Solar Rates Summit, Denver, Colorado, September 2019.

"Whither Standby Rates", EUCI's Canadian Rate Design Symposium, Calgary, AB, June 2019.

"Retail Electricity: Costing and Pricing for Contemporary Challenges", pre-conference workshop at EUCI's Canadian Rate Design Symposium, Calgary, AB, June 2019.

"The Other Side of Residential Revenue Recovery: The Avoided Cost Controversy", post-conference workshop at EUCI's Residential Demand Charges Conference, Nashville, TN, May 2018.

"Attracting and Retaining Large-Customer Loads", EUCI's Canadian Rate Design Symposium, Vancouver, BC, April 2018.

"Basics of Retail Pricing: Traditional and Innovative", pre-conference workshop at EUCI's Canadian Rate Design Symposium, Vancouver, BC, April 2018.

"Retail Pricing to Support Electric Vehicle Charging", EUCI's 7th Annual Southeast Clean Power Summit, Nashville, TN, February 2018.

"Pricing Distributed Energy Resources: Issues and Approaches", pre-conference workshop at EUCI's 7th Annual Southeast Clean Power Summit, Nashville, TN, February 2018.

"The Other Side of Residential Revenue Recovery: the Avoided Cost Controversy", post-conference workshop at EUCI's Residential Demand Charges conference, Charleston, SC, July 2017.

"Net Metering and Solar Energy Pricing," pre-conference workshop at EUCI's Net Energy Metering and Utility Solar Rates Summit, Denver, CO, July 2016.

"Pricing the Purchase of Renewable Energy," post-conference workshop at EUCI's 4th Annual Southeast Clean Power Summit, Atlanta, GA, March 2015.

"Pricing Perspectives of Regulated Utilities on Solar Power," EUCI's Net Metering 2.0 and Utility Solar Rates Conference, Anaheim, CA, January 2015.

Cost of Service and Rate Design; Current Utility Costing and Pricing Challenges; Pricing Renewable Energy; Feed-in Tariffs and Demand Response Alternatives to Supply. Presentations to the Wisconsin Public Utility Institute's Energy Utility Basics Course, 2009–2017.

"The Bill Please," university course and public presentation within the "Decoding the Energy Industry" series; Wisconsin Public Utility Institute, 2014.

Electric Rate Design Principles and Designs (with Dr. Stephen Braithwait), and Pricing Renewable Resources; presentations to the Rate Design and Regulation Workshop, Wisconsin Public Utility Institute, Madison, Wisconsin, 2014.

"Customer Response to Dynamic Pricing: Who Responds and How?," EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles; with Dr. Steven Braithwait.

Cost-of-Service, preconference workshop, EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles.

Critical Peak Pricing: Valuation and Viability, presented at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Georgia Power's FlatBill Program, Risks and Returns, presented, with Monamee Adhikari, Georgia Power Company, at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Retail Pricing for Competitive Power Markets, six presentations on retail pricing and unbundling; Infocast conference February 28-March 2, 2001.

Retail Products and Pricing Under Competition, presented at the Canadian Electricity Association's seminar: Setting Up for New Energy Regulation, April 19, 1999.

Using Risk as the Maker of Prices: Risk-Based Pricing, presented at Infocast's conference: Power Industry Retail Pricing, June 23–25, 1999.

"Designing a Retail Pricing Product Mix for a Competitive Market: A C-VALU Case Study," presented at EPRI's Innovative Pricing Conference, Washington, DC, June 18, 1998, (with Kathleen King and David Kulha).

"Retail Products & Pricing in the Competitive Era," presented at IBC Conference: Successfully Implementing Retail Access, Washington, DC, April 27, 1998.

"Risk-Based Pricing: Making Money in Competitive Markets," EMACS Conference, Atlanta, Georgia, October 14, 1997, (with A. Faruqui, EPRI).

"Real-Time Pricing: Becoming Competitive Before Competition," presented at IBC Conference: Successfully Implementing Retail Profit Projects, Atlanta, Georgia, February 24, 1997, and Las Vegas, Nevada, July 17, 1997.

"Effective Retail Product Design for a Competitive Market," IBC Conference: Developing, Negotiating and Contracting Retail Electricity Prices, Atlanta, Georgia, February 24, 1997, (with Kathleen King).

"Innovative Pricing and Data Requirements," presented at the AEIC Load Research Conference, Washington, DC, August 4–6, 1995.

"Lessons Learned and the Path Forward," presented at EPRI's National Conference on Achieving Success in Evolving Electricity Markets, Atlanta, Georgia, October 10–12, 1995 (with Kathleen King).

"A Real-Time Pricing Primer: Service Design for a Competitive Market," presented at the Missouri Valley Electric Association Marketing Division Conference, Kansas City, Missouri, October 13, 1994.

"Real-Time Pricing: Service Design for a Competitive Market," presented at the American Public Power Association workshop, Scottsdale, Arizona, September 28, 1994.

"Customer Response to Real-Time Pricing: Results from Current Experiments," presented at the 6th National Demand-Side Management Conference, Miami Beach, Florida, March 25, 1993.

"Electricity Pricing Innovations for Retail Sales," presented at the Energy Utilities and Regulation Course, Wisconsin Public Utilities Institute, September 13, 1990; revised and presented again in 1992.

"Innovative Pricing in DSM: Recent Field Tests of Real-Time Pricing," presented at the Energy Demand-Side Research Seminar Series, University of Wisconsin-Madison, April 4, 1990 (with D. W. Caves).

Oral Testimony:

Panelist in Cost-of-Service Methodology review hearings on behalf of Nova Scotia Power, before the Nova Scotia Utilities and Review Board, proceeding NSUARB-NSPI-P-892, Matter No. M05473, December 2013.